Montana – Dakotas Regional Transmission Study

WEST SIDE STUDIES
PROJECT 4

UPPER GREAT PLAINS REGION
Transmission Planning

JULY 2002

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PROJECT 4 SUMMARY

Project 4 modeled a 600 MW wind farm installed near Fort Peck. This project evaluated two different transmission line alternatives and five different power flow schedules to determine their individual impacts on the power system.

The first of the two transmission line alternatives modeled for this Project is referred to as Line 1 throughout this report. Line 1 entailed a 500 kV line from Great Falls to Spokane, a 230 kV line from Shelby to North Lethbridge, and an upgrade of the existing line section between Fort Peck and Great Falls from 161 kV to 500 kV. With these line improvements in place, the power flow was scheduled to Spokane, Salt Lake City, and North Lethbridge.

The second transmission alternative is referred to as Line 2 and consisted of a new 500 kV line from Fort Peck to Denver. With this line in place, the power flow was scheduled to Denver and Salt Lake City.

The two transmission line alternatives mentioned above were shown to have different impacts on the system depending on the market to which the new generation was scheduled. For Line 1, power scheduled to Spokane introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations. For Line 2, power scheduled to Denver introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations.

When power is scheduled to the Salt Lake City area, the model simulation did not perform as well as for the other power schedules. This result can be expected since the particular transmission line alternatives studied do not provide a direct path to the Salt Lake City area.

Dynamic analysis was conducted at six locations. Three-phase and single-line-to-ground fault scenarios were conducted at each location to gauge the effect of the Project in terms to NERC/WECC stability criteria. The system was shown to be transiently stable in all cases, and in general, the Project improved stability over the pre-Project models.

The estimated cost of the first transmission alternative (Line 1) was $574 million. Line 2 was estimated at $503 million. Table 5 summarizes the viability of each of the transmission lines studied. Both of the transmission options studied were shown to be viable when generation was scheduled to the market where the line terminated. Two system intact concerns should be further investigated as recommended in Table 5 for the alternatives that are considered viable. Stability results were acceptable for both line options.

Contingencies that were impacted by the Project would need to be addressed during project development. Two "Contingency Summary" tables illustrate the specific impacts of the viable transmission line options and can be found in the appendices. Recommendations on how to address these issues are also shown. The contingency issues in both viable transmission options are localized to the area surrounding the terminal point of the new line, suggesting a need to extend the Project transmission line and strengthen facilities to support increased power imports.

1. INTRODUCTION AND PROJECT SCOPE

Project 4 of the Montana Transmission Study investigates the effects of a power plant near Fort Peck, Montana. Several 230 kV and/or 500 kV transmission line routes to deliver power to remote load centers were considered.

1.1 Scope

The Project simulated a 600 MW wind powered generation facility near Fort Peck. For this Project, the 600 MW wind facility was modeled as six separate 100 MW wind farms in the area surrounding Fort Peck. For the purpose of discussion, the two transmission alternatives are referred to as “Line 1”, and “Line 2” hereafter, and are outlined as follows with their corresponding load flow schedules:

Line 1: 500 kV line from Great Falls, Montana to Spokane, Washington; 230 kV line from Shelby to North Lethbridge, and upgraded the existing line section between Fort Peck and Great Falls from 161 kV to 500 kV.

- Scheduled to Spokane
- Scheduled to Salt Lake City
- Scheduled to Lethbridge

Line 2: 500 kV line from Fort Peck, Montana to Denver, Colorado

- Scheduled to Denver
- Scheduled to Salt Lake City

Project maps illustrating the line routing for each of the transmission alternatives can be found in the Appendices. Figure 1 illustrates the line routing for Line 1. From Fort Peck, the transmission line was connected to the existing 500 kV bus at Hot Springs, and again at the existing 500 kV bus at Bell. A 230 kV line was added from Shelby to North Lethbridge and tied to the existing 230 kV buses at both Shelby and North Lethbridge. The existing 161 kV line section from Fort Peck to Great Falls was upgraded to 500 kV. At Fort Peck, Havre and Great Falls, transformers were added in order to connect the new line to the existing system.

Figure 2 shows the studied line route for Line 2. From Fort Peck, the transmission line was connected to the existing 500kV bus at Colstrip, to a new 500 kV bus at Dave Johnston, and again to a new 500 kV bus at Daniels Park. A 500 kV to 230 kV transformer was added at Dave Johnston as well as at Daniels Park in order to connect to the existing system.

2. DESCRIPTION OF THE BASE CASES

Two models obtained from the Western Electricity Coordinating Council (WECC) were used to build the Project models. From these, five additional system models were established in order to study and compare the different combinations of transmission lines and schedules. In all cases, the additional Project generation was scheduled by reducing generation in the destination area.

2.1 Line 1 Scheduled to Spokane

Project generation scheduled to the Spokane area with transmission alternative “Line 1” in service is represented by this system model. This model is based on the WECC 2002 Light Summer model, which represents heavy flows from Montana to Washington.

Static VAR Compensators (SVC’s) were added at the new Great Falls 500 kV bus and at the Hot Springs 500 kV bus to counteract excessive voltage rise due to the line charging of the added transmission line.

Area schedules were modified to reflect 600 MW of additional export from Montana, and 600 MW of additional import to Northwest. The swing generators in each of the areas experienced minimal changes in their swing megawatts, and were therefore permitted to adjust for the new system conditions.

2.2 Line 1 Scheduled to Salt Lake City

Based on the WECC 2002 Heavy Summer case, this model simulates power scheduled to Salt Lake City with Line 1 in service.

Of the 600 MW of new Project generation, 585 MW was scheduled to Salt Lake City. This was adjusted to a value less than 600 MW in order to minimize the changes to the swing generators compared to the base model.

2.3 Line 1 Scheduled to Lethbridge

Project generation scheduled to the North Lethbridge area is represented by this system model. The Line 1 scheduled to Lethbridge model is based on the WECC 2002 Light Summer model, which represents heavy flows from Montana to the northwestern area of the system.

In this case, 600 MW of new Project generation was scheduled to Lethbridge. The swing generators in each of the areas experienced minimal changes in their swing megawatts, and were therefore permitted to adjust for the new system conditions.

2.4 Line 2 Scheduled to Denver

The system model is this case represents Project generation scheduled to Denver with Line 2 in service. This model is based on the WECC 2002 Heavy Summer model. The 500 kV bus at Colstrip required an additional SVC to maintain desired voltage levels.

For this case, 600 MW of new Project generation was scheduled to Denver. The swing generators in each of the areas experienced minimal changes in their swing megawatts, and were therefore permitted to adjust for the new system conditions.

2.5 Line 2 Scheduled to Salt Lake City

The next model represents the Project generation scheduled to Salt Lake City with Line 2 (to Denver) in service. The model is based on the WECC 2002 Heavy Summer model.

600 MW of new Project generation was scheduled to Denver and the swing generators in each of the areas experienced minimal changes in their swing megawatts.

3. POWER FLOW ANALYSIS

Two power flow conditions were studied: Category A and Category B. The effect of the Project on the system was gauged by comparing Pre-Project and Post-Project rating and voltage violations. Additionally, power losses were studied for Category A conditions.

3.1 Category A Power Losses

Table 1 summarizes the change in system losses due to the Project. Losses are sorted by area, and are broken up into real power (MW) and reactive power (MVAR) losses. Please note that only those areas with significant changes are included in Table 1. Positive values in the table indicate an increase in system losses, whereas negative values indicate that losses decreased. Values in bold text indicate the area to which the Project has been scheduled.

Table 1 - Project Effect on System Losses by Area

Line Code -->	L1		L1		L1		L2		L2	
Schedule -->	Spokane		Salt Lake		Lethbridge		Denver		Salt Lake	
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR
Total System	55	-1500	160	-725	-82	-2713	-27	-2435	52	-1774
Northwest	**28**	**-379**	69	144	5	-633	-11	-153	5	41
B.C. Hydro	5	51	5	54	-23	-265	0	3	1	10
Alberta	0	-34	-1	-52	**-85**	**-645**	0	0	0	0
Idaho	2	18	7	18	1	13	-1	5	9	71
Montana	5	44	20	91	5	37	11	-926	20	-869
WAPA U.M.	13	-1223	14	-1216	14	-1238	5	-587	5	-591
PACE	1	10	**36**	**171**	1	9	1	38	**41**	**341**
Colorado	0	2	0	-2	0	1	**-21**	**-734**	-30	-868
WAPA R.M.	1	11	11	76	0	9	-10	-75	3	96

The effect of the Project on system power losses is primarily dependent on the combination of the Project line route and the Project schedule. Table 1 indicates that the largest increase in total system losses for this Project occurred for Line 1 scheduled to Salt Lake City. The largest reduction in overall system losses occurred for Line 1 scheduled to Lethbridge. The offloading of existing lines due to an improved flow path caused by Line 1 resulted in a great reduction of losses in British Columbia and Alberta.

Throughout Table 1 there are large reductions in reactive power losses (MVARs). These decreases are the result of line charging of the added transmission lines.

As can be expected, significant changes occur in the export area (WAPA U.M.) and the import area (values in bold) for each schedule. However, due to the physical power flow paths, the Project can be seen to also have some impact on surrounding areas. This is particularly evident for the two cases scheduled to Salt Lake City. Because neither Line 1 nor Line 2 routes directly to the Salt Lake City area, a significant amount of the additional imports to Salt Lake City must come from other transmission paths and sources.

3.2 Category A Violations

Table 2 presents the number of Category A rating and voltage violations for the Project. The first results column gives the number of violations caused or worsened by the Project. The second results column gives violations that were fixed or improved by the Project.

Table 2 - Category A Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	-	-	3	1
		Montana	1	-	-	-
	Salt Lake	Northwest	-	-	-	3
		B.C. Hydro	-	-	-	9
		Alberta	-	4	-	-
		Montana	-	2	-	1
		WAPA U.M.	-	1	-	-
		PACE	4	2	-	2
		WAPA R.M.	-	2	-	-
	Lethbridge	Northwest	-	1	-	1
		B.C. Hydro	-	20	-	4
		Alberta	1	38	3	2
		Montana	1	1	-	-
		WAPA U.M.	-	1	-	-
L2	Denver	PACE	1	-	-	1
	Salt Lake	Northwest	-	-	-	2
		B.C. Hydro	-	-	-	2
		Montana	-	-	-	1
		PACE	3	-	-	2

3.2.1 Line 1 Scheduled to Spokane

As can be seen in Table 2, only one new rating violation and no new voltage violations occurred for this case. This is not unexpected, since the added transmission line routes directly from Fort Peck to the Spokane area, and the additional power flow schedule is mostly carried by the new line without adversely affecting the surrounding system. The single rating violation occurred at Colstrip, where the COLSTP 4 26-500 kV Generator Step-Up (GSU) transformer became marginally overloaded to 100.2% due to increased VAR output. This overload could be addressed by adding additional shunt compensation to the system in place of the unit VAR output.

Three rating violations in the Northwest area were fixed for the schedule to Spokane. The two CHIEFJO GSU transformers and the COUGAR T GSU experience 3% and 1% decreases respectively in their loading. This decrease is due to a reduction of generator output due to the scheduling method, and cannot be considered an improvement brought about by the Project.

One insignificant overvoltage violation of 1.05 pu was corrected when compared to the base case.

3.2.2 Line 1 Scheduled to Salt Lake City

Three of the four rating violations caused by the Line 1 schedule to Salt Lake City are in the area of the known Amps constraint in Idaho. The 161 kV Jefferson phase shifting transformer reached 115.9% of its 100 MVA rating, and two 161 kV lines, Fish Creek-Goshen and Fish Creek-Grace reached 110.3% and 107.5%, respectively. The fourth violation occurred on the 345 kV line from Bonanza (eastern Utah) to Mona which reached 101% of its capacity.
For Line 1 scheduled to Salt Lake City, 11 voltage violations were caused and 15 violations were shown to be corrected. The undervoltages are mainly located along the 230 kV Amps transfer and the adjacent 161 kV line, and are due to the heavy loading of these transfer paths. Line 1 is not the preferred transmission options for schedules to Salt Lake City.

3.2.3 Line 1 Scheduled to Lethbridge

For this case, Table 2 shows two new rating violations: one in Alberta and one in Montana. The single rating violation in Montana occurred at Colstrip, where the COLSTP 4 26-500 kV transformer became marginally overloaded to 100.3% of its rating. The new rating violation in Alberta occurred on a 138 kV to 69 kV transformer (101.9% overloaded). Three rating violations in Alberta that occurred in the base case were fixed with the new line in place.

Line 1 scheduled to Lethbridge caused a total of 58 new voltage violations in Alberta and British Columbia, all of which are overvoltages ranging from 1.05 pu to 1.07 pu. Only six violations were fixed in the same two areas for this scenario. Further investigation into the system model indicates that many of the 500 kV to 240 kV transformers in these areas are not modeled with automatic tap changers.

Beside the voltage violations mentioned above, one violation occurred near Great Falls (Montana), one near Havre (WAPA U.M.), and one near Seattle (Northwest). These three voltage violations were all just above 1.05 per unit.

Line 1 scheduled to Lethbridge fixed six voltage violations in Canada and one on the RINGOLD 115 kV bus (Northwest).

3.2.4 Line 2 Scheduled to Denver

As can be seen in Table 2, only one new rating violation and no new voltage violations occurred for this case. This is not unexpected, since the added transmission line goes directly to the Denver area, and the increased power flow is mostly carried by the new line without adversely affecting the surrounding system. The single rating violation occurred on the Bonanza to Mona 345 kV line which became 100.1% loaded. The increased flow across the Bonanza transfer is the result of a generation offset caused by the Project. The Bonanza-Mona 345 kV line is rated in the model at 650 MVA continuous and a review of this rating may reveal that additional transfer capacity can be achieved.

Line 2 scheduled to Denver corrected one overvoltage that occurred in the base case on the PINTO 345 kV phase shifting transformer in the Four Corners area.

3.2.5 Line 2 Scheduled to Salt Lake City

Similar to Line 1 scheduled to Salt Lake City, two of the three new rating violations occurred in the area of the Amps constraint in Idaho. The Fish Creek to Goshen 161 kV line reached 103.5% of its rating, and the Fish Creek to Grace 161 kV line achieved 100.7% of its rating. In this case, the 345 kV line from Bonanza to Mona became loaded to 119.8% in the system model. Similar to Line 1, this transmission alternative is not the preferred method for transporting power to Salt Lake City.

Line 2 scheduled to Salt Lake City did not cause any new voltage violations, and actually fixed seven voltage violations that existed without the line in place. Two undervoltages were fixed in the Northwest (OPORTUNE and IRVIN 115 kV), two small overvoltages were corrected on the 345 kV system at PINTO, and three other small overvoltage conditions were corrected by the Project: one in Montana and two in British Columbia.

3.3 Category B Violations

Table 3 shows the number of rating and voltage violations affected by the Project for Category B Power Flow. For each schedule, 1,371 single-outage contingencies were analyzed for Line 1, and 1,368 single-outage contingencies were analyzed for Line 2.

Table 3 presents a summary of Category B violations with respect to continuous ratings (Rate 1).

Table 3 - Category B Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	8	9	-	-
		Montana	-	-	-	1
		WAPA U.M.	-	1	-	-
		WAPA R.M.	-	4	-	-
	Salt Lake City	Northwest	3	26	1	-
		Montana	3	21	1	2
		WAPA U.M.	-	16	-	-
		PACE	22	8	4	1
		Colorado	-	-	1	-
		WAPA R.M.	9	4	4	2
	Lethbridge	Northwest	6	10	-	2
		Alberta	-	-	3	-
		Montana	-	-	-	1
		WAPA U.M.	-	1	-	-
		WAPA R.M.	-	3	-	-
L2	Denver	Northwest	2	6	1	-
		Montana	-	5	1	1
		WAPA U.M.	-	1	-	-
		PACE	-	2	1	1
		Colorado	6	-	12	40
		WAPA R.M.	4	-	7	8
	Salt Lake City	Northwest	2	9	1	-
		Montana	-	5	1	-
		WAPA U.M.	-	2	-	-
		PACE	26	35	-	-
		Colorado	7	1	10	41
		WAPA R.M.	16	32	7	9

3.3.1 Line 1 Scheduled to Spokane

For Line 1 scheduled to Spokane, the majority of violations occurred in the Northwest area. The most serious new rating violation occurred on the BEACON N to BELL SO 230 kV line which reached 104% of its rating for contingency BELL MI to BELL SO 230 kV line. Seven out of the eight rating violations are caused by either the contingency mentioned above or the BELL NO to WESTBPA1 230 kV line contingency.

Nine out of the fourteen voltage violations introduced by this scenario occurred during the BELL BPA 500 kV to BELL SO 230 kV transformer outage. The most severe of these undervoltage violations occurred in the Northwest area at CHENEY 115 kV at 0.940 per unit, and at FOURLKS 115 kV and SILVRLAK 115 kV which both dropped to 0.942 per unit. The four new voltage violations in the WAPA R.M. area are due to other contingencies, and the severity is minimal with voltage just below 0.95 per unit. An overall observation of the results for Line 1 scheduled to Spokane is that the new Category B rate violations are centered around the BELL BPA bus. The localization of these violations suggests that transmission outlets in addition to Bell Substation will be necessary to fully utilize this transmission option.

This case had two new non-converged outages: the new Havre-Great Falls 500 kV line, and the new Great Falls-Hot Springs 500 kV line. This indicates that the Project schedule is critically dependent on the new 500 kV transmission corridor. When a section of this transmission path is out of service, the surrounding system cannot support the transfer of the Project generation. A remedial action scheme to trip a portion of the Project generation would be necessary for these two contingencies.

3.3.2 Line 1 Scheduled to Salt Lake City

For Line 1 scheduled to Salt Lake City, of the 37 new Category B rating violations, 22 occurred mainly in the PACE area and 9 occurred in WAPA R.M. area. This case caused 75 new Category B voltage violations in the model and they were fairly widespread throughout the system. The most severe new rating violation occurred on the ARTESIA to HAYDEN 138 kV line which reached 110% of its rating for the contingency BEARS to CRAIG 345 kV line. Further investigation shows that the majority of the new rating violations occur around the known Amps constraint in Idaho, or along the eastern Utah border.

The most severe voltage violation occurred at HAVRE 115 kV with an undervoltage of 0.894 per unit for the HAVRE 161 kV to HAVRE 115 kV transformer outage. The majority of the voltage violations for this case were caused by the following two contingencies; an outage of the MTSGFALL to HOT SPR 500 kV line (added by the Project), and the BELL BPA 500 kV to BELL SO 230 kV transformer outage.

An overall observation of the results for the Line 1 scheduled to Salt Lake City is that there are more Category B violations caused or worsened by the Project than fixed or improved. This indicates that Line 1 is not the preferred Project when power flow is scheduled to Salt Lake City.

Three new outages did not converge for this case:

- Anaconda to Peterson Flats 230 kV (Southwest Montana)
- Amps to Antelope 230 kV (Idaho)

- Havre to Great Falls 500 kV (New line added by the Project)

3.3.3 Line 1 Scheduled to Lethbridge

For Line 1 scheduled to Lethbridge, the six new Category B rating violations and 10 of the 14 new voltage violations occurred in the Northwest area. The most serious new rating violation occurred on the BEACON N to BELL SO 230 kV line, which reached 103% of its rating for the contingency BELL MI to BELL SO 230 kV line. Most of the Category B rating violations were in the area close to the BELL BPA bus.

An overall observation of the results for the Line 1 scheduled to Lethbridge is that very few new Category B rate violations occurred compared to the other scenarios, and all new violations were centered around the BELL BPA bus. Another observation is that all the voltage violations introduced by the Project in the Northwest area were during the BELL BPA 500 kV to BELL SO 230 kV transformer outage which indicates that the Project is primarily serving loads in the Northwest area, and does not adequately support Lethbridge.

As for Line 1 scheduled to Spokane, this case had the same two outages for which the model did not converge indicating a similar condition of critical dependency on the new 500 kV transmission Hiline upgrade.

3.3.4 Line 2 Scheduled to Denver

With the combination of Line 2 and the schedule to Denver, the twelve new rating violations occurred in the Northwest, Colorado, and WAPA R.M. areas. The most severe new rating violation was at Daniels Park near Denver where a line section reached 101% of its capacity. Additionally, the loading of the Waterton 230-115 kV transformer increased by 16% from 99% to 115%.

The most severe voltage violation occurred in the Northwest area at the OPORTUNE 115 kV bus, which dropped to 0.926 per unit for the BELL BPA to TAFT 500 kV contingency.

For Line 2 scheduled to Denver there are 72 Category B violations fixed or improved versus 26 which were caused or worsened, indicating that Line 2 scheduled to Denver has a desirable impact on the system. This result is not unexpected, since the added 500 kV transmission lines connect Fort Peck to the Denver area, and the increased power flow would be supported by the new lines.

No new outage scenarios failed to converge in the model versus the base case contingency analysis.

3.3.5 Line 2 Scheduled to Salt Lake City

For Line 2 scheduled to Salt Lake City, new rating and voltage violations occurred mainly in the PACE and WAPA R.M. areas. The most serious new rating violation was on the ARTESIA to HAYDEN 138 kV line which reached 153% of its rating for the Bears to Bonanza 345 kV line contingency. Further investigation shows that the rating violations that also existed in the base case were worsened by an average of 16.3 % that is a substantial increase. The most severe voltage violation occurred in the Northwest at the OPPORTUN 115 kV bus, which dropped to 0.923 per unit for the BELL BPA to TAFT 500 kV contingency.

Although 67 Category B rating and voltage violations were fixed or improved in the Colorado and WAPA R.M. areas due to the new Line 2 Project, several more violations (109) were caused or worsened in the PACE area. This is an indication that Line 2 is not the preferred Project when power is scheduled to Salt Lake City. Another observation is the desirable impact on the Colorado area when Line 2 is installed, even if power is not scheduled to Denver.

The following three new outages did not converge for this case:

- Emma Park to Upalco 138 kV (Northeast Utah)
- Bears to Craig 345 kV (Northwest Colorado)
- Poncha to San Luis 230 kV (Southwest Colorado)

The increased strain on the known Bonanza constraint is an undesirable effect of this schedule. Line 2 is not an adequate alternative for reaching the Salt Lake City market.

4. DYNAMIC STABILITY ANALYSIS

4.1 Fault Scenarios

The following outage scenarios, both pre- and post-Project, were simulated for a study period of 10 seconds to determine if the Project created any system instability or violation of WECC criteria during these line and generator outages. Each fault location listed was run on the indicated model corresponding to heavy flows through the location of the fault. Locations were chosen using engineering judgment based on a combination of proximity to the Project generators, magnitude of load interrupted, and dynamic response to contingencies on sections of the new transmission line options.

4.1.1 Fault Location 1

A single-circuit three-phase fault near the new Great Falls 500 kV bus was cleared by tripping the faulted line from the new Great Falls 500 kV bus to the new Havre 500 kV bus in normal 3 cycle total clearing time.

A single-circuit single-phase-to-ground fault near the Great Falls 500 kV bus was cleared by tripping the faulted line from the new Great Falls 500 kV bus to the new Havre 500 kV bus in delayed 9 cycle total clearing time.

All 600 MW of wind generation was tripped offline for both fault scenarios due to the absence of load once the faulted line is taken out of service. The model used for this simulation was Line 1 scheduled to Spokane that is based on the WECC

Light Summer model, and has additional heavy power flows through the region of the fault due to the generation schedule.

4.1.2 Fault Location 2

A single-circuit three-phase fault near the new Dave Johnston 500 kV bus was cleared by tripping the faulted line from the new Dave Johnston 500 kV bus to the new Daniels Park 500 kV bus in normal 3 cycle total clearing time.

A single-circuit single-phase-to-ground fault near the Dave Johnston 500 kV bus was cleared by tripping the faulted line from the new Dave Johnston 500 kV bus to the new Daniels Park 500 kV bus in delayed 9 cycle total clearing time.

The model used for this simulation was Line 2 scheduled to Denver that is based on the WECC Heavy Summer model, and has heavy power flows through the region of the fault due to the additional power scheduled to Denver. Manual simulation of the Colstrip ATR was executed.

4.1.3 Fault Location 3

A single-circuit three-phase fault near the Garrison 500 kV bus was cleared by tripping the faulted section from the Garrison 500 kV bus to the GAR1EAST 500 kV bus in normal 3 cycle total clearing time.

A single-circuit single-phase-to-ground fault near the Garrison 500 kV bus was cleared by tripping the faulted section from the Garrison 500 kV bus to the GAR1EAST 500 kV bus in delayed 9 cycle total clearing time.

The model used for this simulation was Line 2 scheduled to Salt Lake City that is based on the WECC heavy summer model and includes additional flows to Salt Lake City due to the Project schedule. Pre-Project scenarios were run on the corresponding base case.

Manual simulation of the Colstrip ATR was executed. Other events include:

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

4.1.4 Fault Location 4

A single-circuit three-phase fault near the Colstrip 500 kV bus was cleared by tripping the faulted line from the Colstrip 500 kV bus to the Broadview 500 kV bus in normal 3 cycle total clearing time.

A single-circuit single-phase-to-ground fault near the Colstrip 500 kV bus was cleared by tripping the faulted line from the Colstrip 500 kV bus to the Broadview 500 kV in delayed 9 cycle total clearing time.

The model used for this simulation was Line 2 scheduled to Salt Lake City that had heavy power flows through the region of the fault. Pre-Project scenarios were run on the corresponding base case.

Manual simulation of the Colstrip ATR was executed for both fault scenarios. Additional events include:

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.
- Post-Project only: A reactor at Fort Peck was brought online at 5 seconds.

4.1.5 Fault Location 5

A single-circuit three-phase fault near the new Great Falls 500 kV bus was cleared by tripping the faulted line from the new Great Falls 500 kV bus to the Hot Springs 500 kV bus in normal 3 cycle total clearing time.

A single-circuit single-phase-to-ground fault near the new Great Falls 500 kV bus was cleared by tripping the faulted line from the new Great Falls 500 kV bus to the Hot Springs 500 kV bus in delayed 9 cycle total clearing time.

A total of 500 MW of wind generation was tripped offline for both fault scenarios due to the absence of load once the faulted line is taken out of service. 100 MW of wind generation was left online to match remaining loads. The model used for this simulation was Line 1 scheduled to Spokane that is based on the WECC Light Summer model, and has heavy power flows through the region of the fault.

4.1.6 Fault Location 6

A single-circuit three-phase fault near the Shelby 230 kV bus was cleared by tripping the faulted line from the Shelby 230 kV bus to the Conrad 230 kV bus in normal 5-cycle total clearing time.

A single-circuit single-phase-to-ground fault near the Shelby 230 kV bus was cleared by tripping the faulted line from the Shelby 230 kV bus to the Conrad 230 kV bus in delayed 25-cycle total clearing time.

The model used for this simulation was Line 1 Scheduled to Lethbridge that is based on the WECC Light Summer model, and has increased flows to the Alberta system. Pre-Project scenarios were run on the corresponding base case.

4.2 Dynamic Stability Study Results

4.2.1 Fault Location 1

Fault scenarios at Location 1 were conducted on Project buses and lines, and are therefore not compared to any pre-Project case. Analysis of the results for faults at this location show that no transient stability violations were created for three-phase or single-line-to-ground faults. Voltages on buses along the new 500 kV Hiline recover to near pre-contingency levels; however, bus voltage at Fort Peck 500 kV is slow to recuperate, taking approximately 40 cycles to rise to within 5% of the initial value. Note that the clearing of the Havre-Great Falls 500 kV line islands the Hiline from the western grid. A mismatch of load to generation is likely to blame for the slow voltage recovery. Due to the irregular availability of wind power, sufficient reserves at the Fort Peck hydro station will be necessary to quickly stabilize voltage during times when wind generation becomes unavailable. This case meets key stability criteria.

4.2.2 Fault Location 2

Three-phase and single-line-to-ground faults at Location 2 did not cause any transient violations of stability criteria. The system proved to be transiently stable for these scenarios. Post-fault voltage levels were higher along the 500 kV Hiline at 1.13 pu, and are very near the 5% post-transient criteria. A post-fault adjustment of shunt reactors may be necessary to minimize post-transient voltage deviation. This case meets all key stability criteria.

4.2.3 Fault Location 3

The system was shown to be transiently stable for faults at Garrison 500 kV with subsequent clearing of a single Garrison-Taft circuit. Post-transient 500 kV voltage levels were slightly higher proceeding the fault. No transient voltage violations were observed for pre- or post-Project, three-phase or single-line-to-ground faults at this location.

The Project was shown to improve a significant number of frequency dips over the pre-Project case. The addition of the Project slightly improved the worst frequency dip by 0.15 Hz over the pre-Project drop of 59.4 Hz for 15 cycles on FT PECK1 13.8 kV. This case meets all key stability criteria.

4.2.4 Fault Location 4

The disturbance at Colstrip 500 kV with subsequent clearing of the Colstrip-Broadview 500 kV line was demonstrated to be transiently stable with no transient voltage violations for any fault scenario or for pre- or post-Project conditions. Note, however that voltage dips exceeding the 25% criteria for load buses were observed at Fort Peck, and may be a violation of the load bus criteria on the distribution system in this area.

The number of frequency events was significantly reduced by the addition of the Project. The addition of the Project improved the worst frequency dip by 0.23 Hz over the pre-Project drop of 59.30 Hz for 15 cycles on COLSTP4 26 kV.

4.2.5 Fault Location 5

Three-phase and single-line-to-ground faults at Location 2 did not cause any transient violations of stability criteria. The system proved to be steady-state stable for all scenarios at this location. As was the case for Location 1, voltage along the 500 kV Hiline was somewhat slow to recover due to the tripping of most of the Project generation. This case meets key stability criteria.

4.2.6 Fault Location 6

Three-phase and single-line-to-ground faults at Shelby 230 kV caused minimal disturbances in both the pre- and post-Project cases. No transient voltage or frequency criteria were violated during these fault scenarios. The interruption of load flow to Lethbridge caused by this fault is not a significant event. This case meets all key stability criteria.

5. COST ANALYSIS

Transmission and substation estimated costs for the individual studies are as shown in Table 4. The generation substations do not include any distribution equipment. The estimated costs began at the low side bushings of each of the six Wind Generation Substation transformers and went through to the designated transmission tie-in buses. Note that each entry in the Substation Cost column includes $30 million in collector substation costs for the wind farm.

Table 4 - Transmission and Substation Costs - Project 4

Line Code	Substation Cost (thousands)	Transmission Costs (thousands)	Total Costs (thousands)
L1	$118,783	$455,433	$574,216
L2	$103,919	$398,694	$502,613

6. VIABILITY ANALYSIS

The feasibility of each transmission line alternative was ascertained given the results of the power flow and dynamic stability analyses. Transmission line options that are considered viable were shown to be acceptable in terms of Category A and dynamic stability criteria. Appropriate project refinements and the mitigation of noted Category B contingencies is expected to be performed with any further project development. Table 5 presents the transmission line options in terms of their viability. A contingency summary table can be found in the appendices for each of the cases determined to be viable.

Table 5 - Viability Summary

Project	Line Code: Description	Schedule	Comments	Viable Project?
Project 4 600 MW Wind near Fort Peck	**L1: 500 kV to Spokane; 230 kV Shelby to Lethbridge**	Spokane	Additional VAR support may be needed at Colstrip	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
		Lethbridge	Dependence on existing B.C.-Alberta transfer. Too many changes to Alberta system.	No
	L2: 500 kV to Denver	Denver	Review rating of Bonanza-Mona 345 kV line.	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No

Line 1 is shown in the table to be a viable alternative for this generation Project when scheduled to Spokane. However, the model does suggest that increased reactive power support would be necessary near Colstrip. Line 2 is also a viable transmission line option when the generation is scheduled to Denver. Further investigation is recommended to determine if a system intact overload of 0.1% on the Bonanza-Mona 345 kV line is representative of an equipment or thermal rating limit of this line section.

Scheduling the generation to Salt Lake City or Lethbridge was not viable for the transmission line options studied. Overloads were observed on known constraint paths in the system intact studies when generation was scheduled to Salt Lake City. The line additions of Line 1 were inadequate for schedules to Lethbridge, illustrated by the fact that the power delivered by the new Shelby-Lethbridge 230 kV line was only 14% of the 600 MW of new generation.

7. CONCLUSIONS

It has been shown through the completion of this study Project that a 600 MW wind powered generation facility installed near Fort Peck, Montana could have a desirable impact on the power system if implemented in conjunction with the indicated viable transmission line alternatives. The results also indicate that some power schedules are not as feasible with the given transmission line alternatives as other power schedules.

For the Line 1 transmission line alternative, it was shown that power scheduled to Spokane introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations. This is a viable alternative when the new generation is scheduled to Spokane.

For the Line 2 transmission line alternative, it was shown that power scheduled to Denver introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations. This is a viable alternative when the new generation is scheduled to Denver.

Since neither of these two transmission alternatives provide for an improved power schedule in the direction of Salt Lake City, it is not unexpected that the Salt Lake City power schedule did not perform as well as the other power schedules. System intact overloads indicated that generation scheduled to Salt Lake City was not viable for the two line options studied in this Project. Generation scheduled to Lethbridge was also not viable due to the fact that the imports to the Alberta system were transported primarily from B.C Hydro as opposed to the Montana area.

For the scenarios studied, the added generation at Fort Peck and the 500 kV Hiline improved stability over the pre-Project cases. Post-transient voltage on the 500 kV Hiline approached a 5% change over its initial voltage for fault Locations 1 and 2. Voltage dips exceeding the 25% criteria for load buses were observed at Fort Peck for a three-phase post-Project fault at Location 4, and may be a violation on the distribution system at Fort Peck.